PATENT APPLICATION

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NON-ORIENTING TUBING HANGER SYSTEM WITH A FLOW CAGE

BACKGROUND OF THE INVENTION

Related Applications

[0001] Applicants claim priority to the invention described herein through a United States provisional patent application titled "Non-Orienting Tubing Hanger System with a Flow Cage," having U.S. Patent Application Serial No. 60/399,478, which was filed on July 30, 2002, and which is incorporated herein by reference in its entirety.

1. Field of the Invention

[0001] The present invention relates generally to production well systems, more specifically to assemblies and methods for achieving installation of a hanger in such systems.

2. Background of the Invention

[0002] Well fluid from a subsea well typically flows up a string of production tubing to a subsea wellhead. Sometimes well fluid is transmitted through a production riser to a Christmas tree on a vessel at the surface of the sea. It is often desirous however to transport the well fluid through a subsea Christmas tree to a collection facility or processing site.

[0003] In one type of subsea tree, the production tubing is suspended on a tubing hanger landed in a wellhead housing. The tree mounts to the wellhead housing and the tubing hanger has an axial through-bore to deliver fluid to the tree. The tubing hanger also has an annulus passage extending through it for communicating with the tubing annulus.

[0004] In another type, the tubing hanger lands in the tree, which is supported on the wellhead housing. The tubing hanger has a lateral port extending from it that aligns a lateral port in the tree.

[0005] In both of these types, the tubing hanger must be oriented, which can be complex in deep water. Also both types require relatively large diameters. To reduce expense, smaller diameter wells and components are desirable. Concentric tubing hangers do not require orientation. However, they typically require check valves for the annulus, thus historically are not used extensively.

SUMMARY OF THE INVENTION

[0006] In the subsea wellhead assembly of this invention, a tubular wellhead member or wellhead housing, which may be considered a tree, has a production port extending through its side for transmitting production fluid or well fluid from the subsea well. The tubing hanger lands in a bore of the wellhead housing and has an inner bore in fluid communication with the string of tubing. The tubing hanger conveys production fluid from the string of tubing to a production port. The production fluid flows through a hanger port extending through a side of the tubing hanger from the bore of the tubing hanger to the production port extending. A diverter or flow cage is positioned adjacent the tubing hanger for diverting the flow of production fluid from the hanger port around a portion of the tubing hanger to the production port. The hanger port can be a plurality of ports extending through a radial portion of the tubing hanger.

[0007] The well fluid contacts the inner surface of the diverter or flow cage after flowing out of the tubing hanger. The diverter can surround the exterior surface of the tubing hanger so that the well fluid flows around a portion of the tubing hanger. The diverter can also include a port or a plurality of ports extending through a radial portion of the diverter that is offset from hanger port for the production fluid to flow from inside the diverter to the interior surface of the wellhead housing. The well fluid then flows between the outer surface of the diverter and the inner surface of the wellhead member to the production port.

[0008] The tubing hanger has one or more tubing annulus ports extending axially through it. Control of the tubing annulus is controlled by a controls cap mounted above the tubing hanger.

BRIEF DESCRIPTION OF THE DRAWINGS

[0009] Figure 1 is an overall sectional view of an upper portion of a non-orienting tubing hanger placed in a wellhead assembly, each being constructed in accordance with this invention.

[0010] Figure 2 is a cross-sectional view of the tubing hanger shown in Figure 1 and taken along the line 2-2 of Figure 1.

[0011] Figure 3 is an enlarged cross-sectional view of the upper portion of a non-orienting tubing hanger taken along the line 3-3 of Figure 2 when placed in the wellhead assembly as shown in Figure 1.

[0012] Figure 4 is an enlarged cross-sectional view of the upper portion of a non-orienting tubing hanger taken along the line 4-4 of Figure 2 when placed in the wellhead assembly as shown in Figure 1.

[0013] Figure 5 is an enlarged cross-sectional view of the upper portion of a non-orienting tubing hanger taken along the line 5-5 of Figure 2 when placed in the wellhead assembly as shown in Figure 1.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENT

[0014] Referring to Figure 1, one configuration for a subsea wellhead assembly 10 includes a low pressure wellhead housing or conductor housing 11, which will locate at the sea floor. Low pressure wellhead housing 11 is a large tubular member that is secured to a string of conductor pipe 13. Conductor pipe 13 extends to a first depth into the well.

[0015] A high pressure wellhead member 15 lands in the low pressure wellhead housing 11. Wellhead member 15 functions both as a wellhead housing and a production tree. High pressure wellhead member 15 secures to a first string of casing 17, which extends through the conductor pipe 13 to a deeper depth into the well. Normally, the first string of casing 21 is cemented in place. A casing hanger 19 and casing 21 are installed in high pressure wellhead member 15 within first string of casing 17, and string of casing 21 is typically cemented into place. Casing hanger 19 lands on a lower shoulder in the interior surface of high pressure wellhead member 15. Casing hanger 19 is sealed by a casing hanger packoff 23 to interior surface 20 of high pressure wellhead member 15.

[0016] A tubing hanger 25 having an interior surface and an exterior surface lands on a shoulder on casing hanger 19. Tubing hanger 25 is sealed by a hanger packoff 28 to interior surface 20 of casing hanger 19. Tubing hanger 25 secures to tubing 27. Tubing 27 extends through string of casing 21 to a desired depth of the well. Tubing 27 is not cemented in place. Tubing 27 defines a production passageway 29 through which production fluids communicate from the well to wellhead assembly 10 before exiting to a production flowline (not shown).

[0017] A bore 31 is formed in wellhead member 15 above tubing hanger 25 for receiving a controls cap (not shown) that provides a barrier and has valves or plugs for controlling entry into

production passageway 29 and access to the tubing annulus. A stringer (not shown) extends from the controls cap into production passageway 29. A wire line plug (not shown) will typically be set in the upper end of tubing hanger passage 29. A production port 33 in high pressure wellhead member 15 above conductor housing 11 extends radially from inner surface 20 of high pressure wellhead member 15 to the outer surface of high pressure wellhead member 15. A pair of tubing annulus passages 34 extend axially through hanger 25 for access to the annulus surrounding tubing 27. An outer cage 35 is formed on the outer surface of tubing hanger 25, which engages the upper end of casing hanger 19 when tubing hanger 25 lands in the well. Outer cage 35 is in fluid communication with production port 33 when tubing hanger 25 lands in the well.

[0018] As illustrated in Figures 1 and 5, a housing recess 37 is formed around the inner circumference of high pressure wellhead member 15. Housing recess 37 and the outer surface of outer cage 35 define an outer chamber 39 that is in fluid communication with production port 33. A casing recess 41 is formed around the outer circumference of tubing hanger 25. Casing recess 41 and the inner surface of outer cage 35 define an inner chamber 43, which is substantially parallel with outer chamber 39. Inner chamber 43 defines an inner cage 45 as the region or portion of tubing hanger 25 that is surrounded by inner chamber 43.

[0019] As illustrated in Figures 2 and 3, at least one hanger port or radial opening 47 is formed in inner cage 45. Preferably there are a plurality of radial openings 47 along inner cage 45. Inner chamber 43 is in fluid communication with passageway 29 through openings 47. Openings 47 transmit production fluid from passageway 29 into inner chamber 43. Typically openings 47 are formed intermittently along a radial portion that is less than one-half of the circumference of inner cage 45.

[0020] At least one diverter port or radial opening 49 is formed in outer cage 35. Preferably there are a plurality of radial openings 49 along outer cage 35 (as shown in Figures 2 and 4). Outer chamber 39 is in fluid communication with inner chamber 43 through openings 49. Openings 47 transmit production fluid from passageway 29 into inner chamber 43, from which openings 49 transmit production fluid to outer chamber 39. Typically openings 49 are formed intermittently along a radial portion that is less than one-half of the circumference of outer cage 35. Preferably there are no openings 49 formed in the radial portion of outer cage 35 surrounding the radial portion of inner cage 45 where openings 47 are formed. Production fluid must flow through inner chamber 43, around a portion of inner cage 45, and through openings 49 on the opposite radial portion of outer cage 35.

[0021] There is no need for aligning openings 49 with production port 33. Typically, openings 49 will be misaligned with production port 33 when landed. With openings 49 facing a solid portion of high pressure wellhead member 15, rather than production port 33, the production fluid must communicate through outer chamber 39 around some portion of outer cage 35 to production port 33. The combination of inner chamber 43 and outer chamber 39 allows tubing hanger 25 to land facing any direction.

[0022] Seals 51 and 53 (Figure 1), located above and below outer cage 35 sealingly engage the inner surface of high pressure wellhead member 15 when tubing hanger 25 lands in high pressure wellhead member 15. Seals 51 and 53 block the flow of production fluid from outer chamber 39 above and below tubing hanger 25. Production port 33 communicates production fluid exiting from tubing hanger 25 to a flowline or pipeline (not shown) that carries the production fluids away from wellhead assembly 10. Production valves (not shown) are mounted to the exterior of wellhead member 15 for controlling well fluid flow.

[0023] In operation, the well is drilled and cased as shown in Figure 1. To do so, conductor housing 11, with a string of conductor pipe 13, is landed and cemented into the well to a certain depth. High pressure wellhead member 15, with first string of casing 17 extending from high pressure wellhead member 15, is then landed and cemented into the well at a deeper depth. A casing hanger 19 with casing 21 is then landed and cemented into the well. Hanger packoff 23 sealingly engages hanger 19 with inner surface 20 of high pressure wellhead member 15.

[0024] Tubing hanger 25, with tubing 27 extending down to production depth, is landed to complete the well. Hanger packoff 28 sealingly connects tubing hanger 25 to inner surface 20 of casing hanger 19. Outer cage 35 lands straddling production port 33 and housing recess 37 of high pressure wellhead member 15. Typically, openings 49 will not open directly to the opening to production port 33 because tubing hanger 25 is not oriented as it is landed. Seals 51 and 53 sealingly engage the outer surface of tubing hanger 25, above and below outer cage 35 and housing recess 37, to inner surface 20 of high pressure wellhead member 15.

[0025] A controls cap is mounted to wellhead member 15 above tubing hanger 25. After valves (not shown) and flow lines (not shown) are connected to production ports 33, the operator can remotely actuate the production valves so that production fluid entering the well below may flow or be pumped up passageway 29 in tubing 27 towards wellhead assembly 10. Because bore 31 at the top of wellhead assembly is capped by the controls cap, the production fluid must exit passageway through openings 47. The total area of openings 47 is greater than the area of passageway 29. Therefore, as the production fluid passes through openings 47 to inner chamber 43, as designated by arrow A in Figure 2, the velocity of the production fluid traveling through each opening 47 is less than the velocity of the production fluid before reaching openings 47.

[0026] The production fluid must flow through inner chamber 43, around a radial portion of inner cage 45 on its way towards openings 49. The production fluid flows through openings 49 into outer chamber 39, as designated by arrows B in Figure 2. Typically, the total area of openings 49 is larger than the area of passageway 29. Therefore, the production fluid has a smaller velocity through each opening 49 than the velocity of the production fluid before entering openings 47 toward inner chamber 43. Having production fluid contacting the inner surface of wellhead member 15 with a reduced velocity reduces tendency for wear on wellhead member 15.

[0027] The production fluid flows through outer chamber 39, typically around a radial portion of outer cage 35 on its way toward production port 33, as designated by arrows C, because openings 49 will typically land oriented away from the opening to production port 33. Seals 51 and 53 prevent the production fluid from exiting outer chamber 39 until the production fluid flows to production port 33. Preferably, the opening to production port 33 has a larger area than the area of passageway 29. Therefore, the production fluid velocity through production port 33 is less than the velocity in passageway 29. The production fluid communicates from production port 33 to a production flowline (not shown) or to a riser (not shown), which carries the production fluid to a platform for processing.

[0028] Diverting the production fluid through inner chamber 43 before the fluid contacts the inner surface of high pressure wellhead member 15 reduces the erosion that may be experienced due to production flow under extreme service conditions. Inner cage 45 and outer cage 39 act together to reduce the velocity of the production fluid when it initially engages high pressure wellhead member 15. Inner and outer cages 45 and 39 are maintainable parts within tubing hanger 25. Wear on the wellhead member 15 can be minimized by using inner and outer cages

45 and 39 in tubing hanger 25 to engage the production fluid at higher velocities, and to reduce the velocity of the production fluid.

[0029] The production fluid passes through openings 47 and encounters the inner surface of outer cage 45 before engaging high pressure wellhead member 15. Openings 47 do not have to be oriented in any particular direction relative to production port 33 to achieve this benefit. Accordingly, operator does not have to employ an orienting system to automatically guide tubing hanger 25 as it lands in high pressure wellhead member 15. As discussed above, the reduced velocity of the production fluid engaging wellhead member 15 from openings 49 allows for tubing hanger 25 landings where openings 49 do not open directly to the opening of production port 33.

[0030] While the invention has been shown in only one of its forms, it should be apparent to those skilled in the art that it is not so limited, but is susceptible to various changes without departing from the scope of the invention. For example, the size of the openings in the inner cage, outer cage, and production port could vary to create differing production fluid velocities at the different stages the production fluid communicates through. Similarly, while the tubing hanger is shown inside the wellhead, it may equally be applied inside a tubing head spool.